

Review of Experience with Competitive Procurement for Transmission Facilities

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1. Introduction and Purpose

Under the *Electric Statutes Amendment Act* (ESA Act), introduced in November 2009, the Government of Alberta is responsible for approving the need for critical transmission infrastructure (CTI). In addition, based on changes implemented by the ESA Act, the Lieutenant Governor in Council (LGIC) may make regulations regarding who may apply to the Alberta Utilities Commission (AUC) for authority to construct and operate transmission facilities. The determination regarding who may apply may be made based on a competitive process or some other method or process.

CTI must be developed in a timely and cost-effective manner. In anticipation of the application of a competitive procurement process for the selection of the party to construct and operate the CTI, the Alberta Electric System Operator (AESO) is developing such a process.

Power Advisory LLC (Power Advisory) was engaged by the AESO to assist it in evaluating the experience in various jurisdictions with the application of competitive procurement processes for transmission facilities, focusing in particular on Texas and the United Kingdom (UK). This report reviews the experiences in Texas and the UK and provides insights that the AESO can employ with respect to developing a process for the competitive procurement of transmission facilities.

1.1 Contents of This Report

This is Power Advisory's review of the experience with competitive procurement processes for transmission facilities. The first chapter is this introduction and reviews our relevant experience. The second chapter reviews the potential role of the entity selected by the AESO in the competitive procurement process (Selected Entity) with respect to the CTI project. Chapter 3 reviews Texas' experience with competitive renewable energy zones. Chapter 4 reviews the UK's experience with competitive procurement of transmission facilities that are built to interconnect offshore wind projects to the UK grid. Chapter 5 briefly reviews the competitive framework developed by the Ontario Energy Board for selecting transmitters that will be designated to develop network transmission facilities. Chapter 6 reviews at a high level the framework employed in Brazil for the competitive procurement of transmission facilities. Chapter 7 summarizes our findings and reviews considerations associated with the design of a competitive procurement process for Alberta.

1.2 Relevant Experience of Power Advisory

Power Advisory offers extensive experience with respect to transmission investment analysis and the development and evaluation of competitive procurement frameworks for electricity resources. We reviewed the Electric Reliability Council of Texas's (ERCOT's) competitive renewable energy zones (CREZ) framework for the Ontario Energy Board (OEB or Board) as part of its transmission connection cost recovery review proceeding. In addition, we assisted the OEB with the development of its transmission project development planning process under which licensed transmitters will compete for the right to develop (and ultimately construct and own) transmission facility expansions. For this project we reviewed the criteria that were employed by the Public Utility Commission of

Texas (PUCT) for the selection of transmission service providers to build the required CREZ facilities and also reviewed the framework employed by the United Kingdom’s Office of Gas and Electricity Markets (Ofgem) for selecting the parties that would own and operate transmission facilities to connect offshore wind projects to the UK grid. In addition, team members have evaluated proposals to build transmission facilities across North America, including Alberta, and to better integrate these jurisdictions. Team members have also identified barriers to the development of major transmission facilities and outlined policies to address these barriers for Natural Resources Canada. Finally, we have assisted with the development or evaluation of over twenty competitive procurement frameworks for energy facilities.

2. Possible Role of Selected Entity with Respect to CTI Project

In its Discussion Paper (Competitive Procurement Process for Critical Transmission Infrastructure), the AESO outlined two alternatives that resulted in significantly different roles for the Selected Entity, i.e., the party selected by the AESO pursuant to its competitive procurement process. While these alternatives are initial proposals, they are reviewed here because they provide useful context with respect to the processes that were or are being employed in Texas, the UK, Ontario and Brazil.

In the first alternative (the “Own Alternative”), the Selected Entity would enter into a contract with the AESO to design, finance, build, own and maintain the CTI project. The Selected Entity would also prepare and file a Facility Application (FA) with the Alberta Utilities Commission (AUC) for approval. As part of this effort, the Selected Entity would secure land access and obtain rights-of-way for the facilities. The payments made by the AESO to the Selected Entity would be recovered from transmission system users pursuant to AESO’s market rules and tariffs.

Under the second alternative (the “EPC Alternative”), the AESO would administer a competitive tender process to select an entity that would essentially provide EPC services for the CTI project. The Selected Entity (known as “EPC Entity” under this alternative) would design and build the CTI project and then transfer the project to the incumbent Transmission Facility Owner (TFO), in exchange for payments from that TFO pursuant to the EPC Contract. Once the project has been placed into service, the incumbent TFO would be remunerated for its costs of owning and operating the project under its AUC approved cost of service. The EPC Entity and the incumbent TFO would coordinate regarding the preparation and filing of the Facility Application.

3. Review of the Texas Competitive Renewable Energy Zones

3.1 Overview of CREZ

As part of a major effort to promote the development of wind energy, Texas developed Competitive Renewable Energy Zones (CREZs) to identify geographic regions with significant wind potential, and to develop the transmission investment required to realize that wind resource potential. The specific objectives of establishing CREZs were to:

- ensure that sufficient transmission infrastructure is built to meet the State’s goal for renewable energy;
- improve the coordination between the construction of transmission facilities and the associated renewable generation facilities; and

- avoid duplication in determining the need for new transmission facilities (e.g., between the CREZ case and any subsequent Certificate of Convenience and Necessity (CCN) proceeding).

The CREZ Rule promulgated by the PUCT outlined the process that would be used to designate the CREZs. The CREZ framework expedited the process by which new transmission projects serving renewable energy resources may be approved by the PUCT and reduced the risk that a utility's construction of transmission to serve a potential wind zone might be challenged as not providing benefit to the utility's customers. The identification of CREZs also reduces the development risks for renewable generation by ensuring the development of the transmission required to deliver the output of that generation to loads within Texas.

The PUCT outlined the rationale for CREZs as follows:

“The rapid development of wind power in West Texas since 2001 has shown that wind farms can be built more quickly than transmission... This timing difference poses a dilemma for planning: it is difficult to know whether a new transmission line will be needed if the generation facilities do not yet exist, but a wind farm is difficult to finance if there is no certainty that sufficient transmission will be available. Senate Bill 20 is an effort to solve this dilemma by authorizing the Commission to identify areas with sufficient renewable energy potential, identify the transmission facilities that could serve the area, and establish the need for new transmission facilities serving the area, even if no specific renewable generation projects exist or are under construction.”¹

The PUCT conducted two rulemakings with significant public participation and conducted three evidentiary hearings. The first two hearings designated the CREZs (i.e., established the zones to be developed) and CREZ Transmission Plan (CTP) (i.e., identified the specific transmission facilities that would be built to realize the wind potential in these zones). The third hearing designated the Transmission Service Providers (TSPs) that would develop and own the transmission facilities included in the CTP. As part of rulemakings, the PUCT followed its typical practice of issuing draft rules and providing opportunities for parties to comment on the rules. Under such rulemakings the PUCT typically issues draft rules, receives comments from interested parties on the draft rules, and reply comments in which parties respond to comments offered by other parties. In addition, the PUCT typically conducts a public hearing at which parties are invited to comment on the rule. Upwards of fifty parties participated in these proceedings. Ultimately, twenty one parties filed statements of interest indicating their intent to file a CTP proposal.

3.2 Institutional Context

The majority of Texas (about 85% of electric load) participates in a market that is overseen by the Electricity Reliability Council of Texas (ERCOT). Unlike most other competitive markets, ERCOT doesn't administer a formal market for the purchase and sale of energy. ERCOT does oversee a balancing energy services market which is used to address variations between the balanced demand and supply schedules provided by market participants and their actual requirements and deliveries.

¹PUCT, Need for Transmission and Generation Capacity in Texas: Renewable Energy Implementation and Costs, December 2006, p. 14.

ERCOT also oversees various ancillary markets that support the bilateral market.²The energy traded through the markets administered by ERCOT represents a relatively small fraction of the total demand in ERCOT. Since ERCOT is located entirely within Texas, it is exempt from FERC oversight or regulation.

The ERCOT market is one of the most competitive wholesale power markets in North America. New generation development since the market was restructured in 1995 has provided about 41,000 MW of capacity, representing almost half of all capacity.³

The PUCT oversees the ERCOT market and serves as the market monitor. The PUCT also reviews proposals for the construction of new transmission facilities.

Texas has a renewable portfolio standard (RPS) of 5,880 MW of renewable capacity by 2015 and a target of 10,000 MW by 2025. Given a favourable wind resource, federal renewable energy production tax credit of 2.1 cents/kWh and a market where natural gas-fired generation is the marginal resource for the vast majority of time, there has been considerable wind project development. Transmission congestion in west Texas has become an increasingly important issue over time and alleviating this congestion was a critical driver in the CREZ process. As of December 31, 2009, Texas had 8,916 MW of wind capacity in operation, with over 900 MW added in 2009.⁴During at least one period in 2009, wind generation served 25% of customer load.⁵

Transmission costs are paid by load, except for direct interconnection costs which are assigned to the interconnecting generation. The costs of CREZ-related transmission will be rolled into ERCOT-wide transmission rates and paid by load. Transmission is priced using a postage stamp rate, with rates uniform regardless of location.

3.3 The CREZ Framework

Under Senate Bill 20 the PUCT was required to designate CREZs throughout the state and to develop a plan to construct the transmission necessary to deliver the output from renewable energy technologies in these zones. The PUCT directed ERCOT, in its role as coordinator of transmission planning and analysis for the ERCOT region, to complete a study of possible transmission improvements and to provide estimates of the transmission capital costs and forecasted system benefits from the designation of different areas in the state as CREZs. ERCOT (through a consultant with expertise in this area) first identified the areas of the state that contained the best wind resources. Those areas, their wind generation potential, and the expected costs of associated transmission that would be required to develop that generation were identified in a report filed with the PUCT (CREZ Transmission Alternatives Report).⁶The various transmission plans were developed through an open stakeholder process that sought to accommodate many of the potential zones in various combinations.

² ERCOT also administers transmission access and coordinates transmission planning.

³ ERCOT, *2009 Annual Report*, p. 2

<http://www.ercot.com/content/news/presentations/2010/2009%20ERCOT%20Annual%20Report.pdf>

⁴ ERCOT, *2009 Annual Report*, p. 3.

⁵ ERCOT, *2009 Annual Report*, p. 8.

⁶ERCOT, "Analysis of Transmission Alternatives for Competitive Renewable Energy Zones in Texas", December 1, 2006. http://www.ercot.com/content/news/presentations/2006/ATTCH_A_CREZ_Analysis_Report.pdf

ERCOT then identified specific transmission upgrades that would allow varying levels of new wind generation to be installed in these areas of significant wind potential.

The enabling legislation specified the criteria to be used by the PUCT in establishing the CREZs as: (1) sufficiency of renewable energy resources and land areas to develop renewable generating capacity from renewable energy technologies; and (2) the level of financial commitment by generators for each potential CREZ. To assess the level of financial commitment the PUCT indicated that it would consider “existing development, signed and pending interconnection agreements (IAs) for units not yet in service, fees paid by generators for interconnection studies, executed leasing agreements with landowners, voluntary letters of credit assuring the developer’s intent to build in the CREZ.”^{7,8}

Using these criteria, the PUCT designated as CREZs five zones (McCamey, Central, Central West, Panhandle A, Panhandle B) that were identified in the CREZ Transmission Alternatives Report. These five zones are identified in Figure 1 below. To assist in identifying the desired transmission improvements, the PUCT requested ERCOT to perform a “CREZ Transmission Optimization Study”. This study identified five alternatives which ranged from \$2.95 billion to \$6.38 billion and would interconnect from 12,053 to 24,859 MW of wind generation.^{9,10}

⁷PUCT, “Rulemaking Relating to Renewable Energy Amendments” (CREZ Rulemaking), December 1, 2006, p. 4.

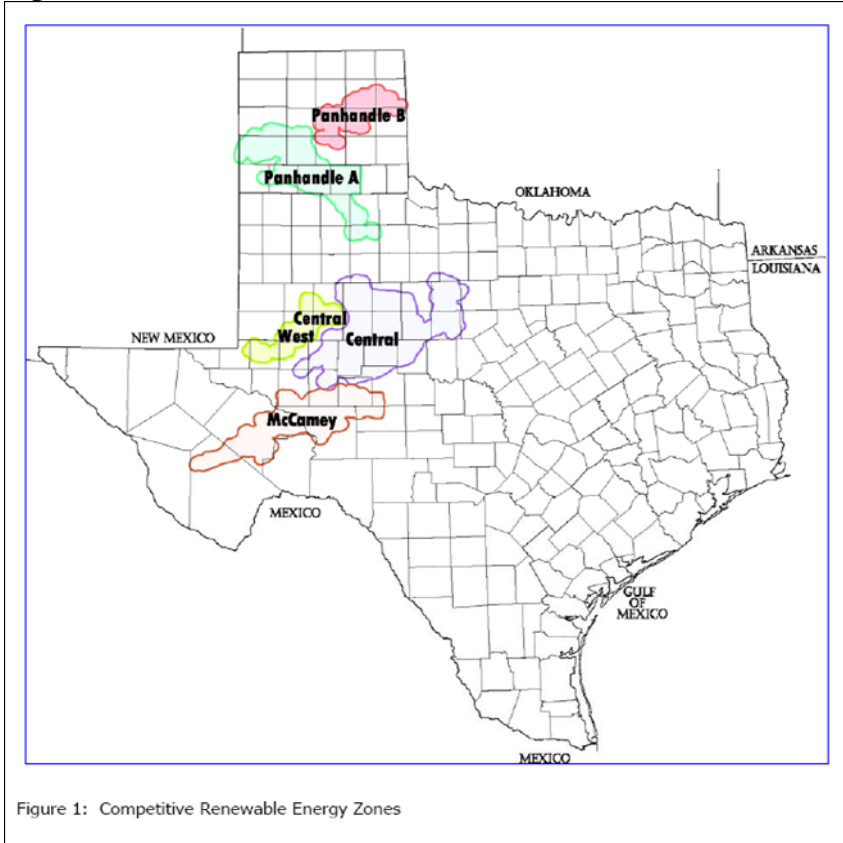
⁸Developers are required to take service under the CREZ transmission facilities within one year of notification by the TSP that the facilities can accommodate the output of the facilities. Developers risk forfeiting any collateral if they fail to take service within 12-months of such a notification, unless they receive an extension from the PUCT.

⁹ ERCOT, CREZ Transmission Optimization Study, April 2, 2008. Included within these CREZ capacity totals is 6,903 MW of existing wind generation or projects that had signed interconnection agreements. Found at:

<http://www.ercot.com/news/presentations/2008/index>

¹⁰The original CREZ Transmission Optimization Report was a planning-level evaluation to identify which areas of Texas were best suited to the expansion of wind generation and what transmission infrastructure would be necessary to transmit the generation capacity in those regions to the population centers of the state. The study included very preliminary cost estimates and designated the general locations of substations and transmission routes from a planning-level perspective. As a planning study, it didn’t consider actual rights of way and estimated transmission line costs on a standard per unit cost for each facility rating. The cost estimates were also in 2008 dollars. The costs estimates did not include any financing costs or contingency allowance.

Figure 1



A fundamental element of this process was to promote competition in the construction and ownership of these projects. The PUCT sought to encourage new entrants given the magnitude of required investment, the scope of the required facilities and short time frame for placing the projects into service. The PUCT also believed that new entrants would promote innovation and spread the risks associated with this required level of investment.

Therefore, the PUCT also instituted a rulemaking to set the criteria for selecting the transmission service providers (TSPs) that would build and own the transmission projects identified in the CREZ Final Order.¹¹ These criteria are reviewed below. The framework outlined by the PUCT required a prospective TSP to first demonstrate that it has the ability to construct, operate and maintain the facilities. With these criteria established and the corresponding rules adopted, parties interested in constructing CTP projects filed expressions of interest with the PUCT. The PUCT then selected the TSPs employing the criteria that it developed. The selection of TSPs took about 12 months from issuance of the criteria to selection.

Once a preferred TSP is selected for a specific CTP facility that TSP must prepare and file the CCN required for that project. After the TSP files the CCN application, generation developers in the relevant CREZ must post a letter of credit or other collateral equal to 10% of their share of CREZ

¹¹<http://www.puc.state.tx.us/rules/subrules/electric/25.216/34560adt.pdf>

facility costs.¹² If this requirement isn't satisfied then the PUCT can reconsider the CREZ designation.¹³

The CREZ Final Order also identifies a set of transmission improvements, the cost of which will be rolled into the uniform transmission tariff. "Each new or upgraded line will be identified by voltage level, and by where the line will connect to the existing grid. Some of the transmission improvements may not be in close proximity to the intended development, and may serve purposes in addition to facilitating renewable energy development in the zone. The order will also include an estimate of the maximum generation capacity that the CREZ can accommodate once the improvements identified in the order are in service."¹⁴

The TSP may propose modifications to the parameters included in the CREZ order if its study reveals alternatives that would reduce costs or increase the amount of generating capacity that the transmission improvements for the CREZ can accommodate.

3.4 Criteria for Selecting TSPs

The PUCT established a multi-step process to select the TSPs to build the CTP facilities. First the PUCT initiated a proceeding inviting the interested TSPs to file CTP proposals. For existing CTP facilities that required an upgrade or modification, the existing owner of the facility was the Designated TSP for the CTP facility, unless the owner requested that a different Interested TSP be selected or good cause existed to select another transmission service provider. For new CTP facilities, the PUCT selected a Designated TSP based on the criteria discussed below.

The rules for selecting the TSPs specify that they will be selected based on the interested TSP's:

- "current and expected capabilities ... to finance, license, construct, operate, and maintain the CTP Facility or Facilities in the most beneficial and cost effective manner and the expertise of the Interested TSP's staff,
- projected capital costs and operating and maintenance costs for each CTP Facility,
- proposed schedule for development and completion of each CTP Facility,
- financial resources,
- expected use of historically underutilized businesses unless the Interested TSP is an electric cooperative or municipally owned utility, and
- understanding of the specific requirements to implement the CTP Facilities in its CTP Proposal and, if applicable,
- previous transmission experience and maintenance costs for its existing transmission facilities."¹⁵

The rules also require that the prospective TSPs provide:

- "a description of the interested TSP's CCN process;

¹² This financial security is ultimately returned to the generation developers if they build their project and connect to the network.

¹³ Rule 25.17 (c)(6)

¹⁴ CREZ Rulemaking, p. 5.

¹⁵ <http://www.puc.state.tx.us/rules/subrules/electric/25.216/25.216.pdf>

- a general description of the proposed structure, conductor types, and right-of-way;
- the projected in-service date;
- the type of resources contemplated for licensing, design, engineering, material and equipment procurement, right-of-way and land acquisition, construction, and project management;
- the type of resources contemplated for operating and maintaining each CTP facility;
- the capability and experience of the TSP to comply with all on-going scheduling, operating, and maintenance activities required;
- resumes for key management personnel;
- a demonstration that the TSP's business practices are consistent with good utility practices for proper licensing, designing, right-of-way acquisition, constructing, operating, and maintaining CTP facilities;
- a summary of law violations found or current investigations;
- the estimated direct costs to construct representative structures;
- a detailed estimate of the anticipated average annual operating and maintenance cost;
- the actual average direct operating and maintenance cost if the TSP is an incumbent utility;
- the overhead rate for managing third-parties and the willingness to maintain the overhead rate;
- the TSP's preexisting procedures and historical practices, or a detailed description of the plans for acquiring right-of-way and land and managing right-of-way and land acquisition for transmission facilities;
- the TSP's preexisting procedures and historical practices, or a detailed description of its plan for mitigating the impact of transmission facilities on affected landowners and for addressing public concerns regarding transmission facilities;
- a proposed financial plan that confirms the TSP has adequate capital resources and no significant negative impact on the creditworthiness or financial condition will occur as a result of the construction, operation, and maintenance of the CTP facilities;
- an affidavit by an officer stating that the information in the application is true and that the TSP will comply with the rules and PURA (Public Utility Regulatory Act);
- other evidence the TSP provides supporting its selection; and,
- unless the TSP is an electric cooperative or municipally owned utility, a description of the use of historically underutilized businesses.”¹⁶

The PUCT also requested utilities to indicate the cost of financing \$100 million (municipal utilities) and \$500 million (privately held) of debt given their credit rating for 1, 3, 5, 10 and 30 year terms. Interestingly, the privately held TSPs were also required to indicate their proposed return on equity if they were selected. The rules also specify additional financial criteria and general requirements including how investment grade status is established and requiring a summary of any history of bankruptcy, dissolution, merger or acquisition of the TSP.

¹⁶<http://www.puc.state.tx.us/rules/subrules/electric/25.216/34560adt.pdf>, p. 4 as cited in <http://www.lcra.org/library/media/public/docs/energy/crez/PUCFinalOrder.pdf>, p. 4

The PUCT summarized the financial factors considered as:

- “the current and expected capabilities of each interested TSP to finance, license, construct, operate, and maintain CTP facilities in the most beneficial and cost-effective manner;
- each interested TSP's projected costs for financing, construction, and operation and maintenance;
- an interested TSP's average direct operating and maintenance costs-per-mile of same-voltage transmission lines during the last five calendar years (when applicable);
- an interested TSP's estimated overhead rate for managing third parties (when applicable); and
- each interested TSP's current and projected financial resources.”¹⁷

The PUCT also noted that

- “regarding each TSP's current and projected financial resources, of particular concern are each TSP's demonstration of available, adequate resources to finance requested CTP facilities;
- a TSP's current credit rating by a nationally recognized credit agency (when applicable); and
- whether each TSP's creditworthiness or financial condition would suffer a significant negative impact as a result of its being assigned varying sizes of CTP facilities.”¹⁸

3.4.1 Other Criteria for Specific Types of CTP Projects

While considerable weight was given to the financial capability of the prospective TSP and its demonstrated ability to secure appropriate financing, consideration was also given to (i) balancing financial requirements with available resources, (ii) the selection of multiple TSPs for the projects and (iii) the proximity of facilities to each other and resulting economies. The order issued by the PUCT doesn't specify the relative weights applied to these different considerations, which are further discussed below.

Given the magnitude of required investment and current financial market conditions, the PUCT recognized “the importance of striking the proper balance between selecting a large pool of TSPs to participate in the CTP in order to spread financial risk, introduce novel technologies, and diversify sources of skills and materials against selecting a small number of TSPs in order to avoid unnecessary complexity and coordination difficulties”.¹⁹

The PUCT also noted that “given the current economic climate and the strong qualifications of many of the interested entities in this docket, the proper balance will be struck through the selection of several incumbent TSPs as well as the strongest new entrants.”²⁰

The PUCT also sought to assign geographically proximate projects to the same TSP when possible. The PUCT noted that

“Ensuring that each selected TSP's projects are close together (or in the case of incumbent TSPs, are at least close to their pre-existing service areas) provides several advantages. Economies of scale can be better employed. For example, multiple

¹⁷<http://www.lcra.org/library/media/public/docs/energy/crez/PUCFinalOrder.pdf>, p. 8.

¹⁸<http://www.lcra.org/library/media/public/docs/energy/crez/PUCFinalOrder.pdf>, p. 8.

¹⁹<http://www.lcra.org/library/media/public/docs/energy/crez/PUCFinalOrder.pdf>, p. 9.

²⁰<http://www.lcra.org/library/media/public/docs/energy/crez/PUCFinalOrder.pdf>, p. 9.

facilities can be addressed by a single service center. Additionally, the difficulties of coordinating with multiple TSPs during the planning, certification, construction, and operation and maintenance stages will be reduced. Furthermore, the TSPs will not be required to familiarize themselves with multiple regions of the state.”²¹

The PUCT also considered the size and resources of the TSP relative to the facilities to be assigned. The PUCT noted that its

“allocations of CTP facilities should reflect each TSP's demonstration of significant experience with large-scale energy projects, the capacity to finance a large CREZ assignment without a significant negative impact on creditworthiness or financial condition, the importance of experience working with landowners and other members of the public to reach mutually beneficial arrangements, and the capability to expand their operations to include CTP facilities promptly and effectively. While the size of an interested TSP's current service area was considered when applicable, this was not the sole determining factor used by the Commission when determining the appropriate total amount of each TSP's assignment.”²²

3.5 Selection of TSPs

3.5.1 Overview of PUCT Process

The cost of service for the CREZ facilities will ultimately be established when the TSPs file for recovery of the costs of the facilities after the start of commercial operation. At this point the PUCT will evaluate the prudence of the construction costs of these facilities, as necessary. As a result, the Interested TSP's proposed costs of constructing the CREZ facilities was given less weight in the PUCT's selection process. Interested TSP's were required to identify which CREZ facilities they sought to build and the estimated costs of building these facilities. From this information PUCT staff was able to calculate the construction cost/mile of the CREZ facilities that each Interested TSP was proposing to build. This information was considered by the PUCT when selecting TSPs. TSPs are required to provide firm cost estimates and project schedules six months after the CCN is approved. These cost estimates and project schedules will be monitored and TSPs will be required to explain material variances from these estimates.

The PUCT's primary consideration in the selection process for TSPs was their financial capability.²³ Given the magnitude of required investment, the PUCT sought broad participation in the development and construction of the CREZ facilities. Only one new entrant wasn't selected given concerns with its financial capability. Based on guidance provided by new entrants, the PUCT believed that they required an investment of approximately \$500 million to make participation in the process sufficiently attractive. To some degree facilities were allocated to incumbent TSPs based on their financial capabilities with less well capitalized TSPs being allocated a smaller share of the facilities.

²¹<http://www.lcra.org/library/media/public/docs/energy/crez/PUCFinalOrder.pdf>, p. 10.

²²<http://www.lcra.org/library/media/public/docs/energy/crez/PUCFinalOrder.pdf>, p. 10-11.

²³ Phone call with Brian Almond, Director of Transmission Analysis, Public Utility Commission of Texas, November 19, 2010.

For much of this period, TSPs financial capabilities were constrained by the ongoing financial crisis. As a result, TSPs ability to fund major new investment was limited by available cash, lines of credit, and limited borrowing. This increased the need for participation by a greater number of TSPs.

3.5.2 TSPs Selected

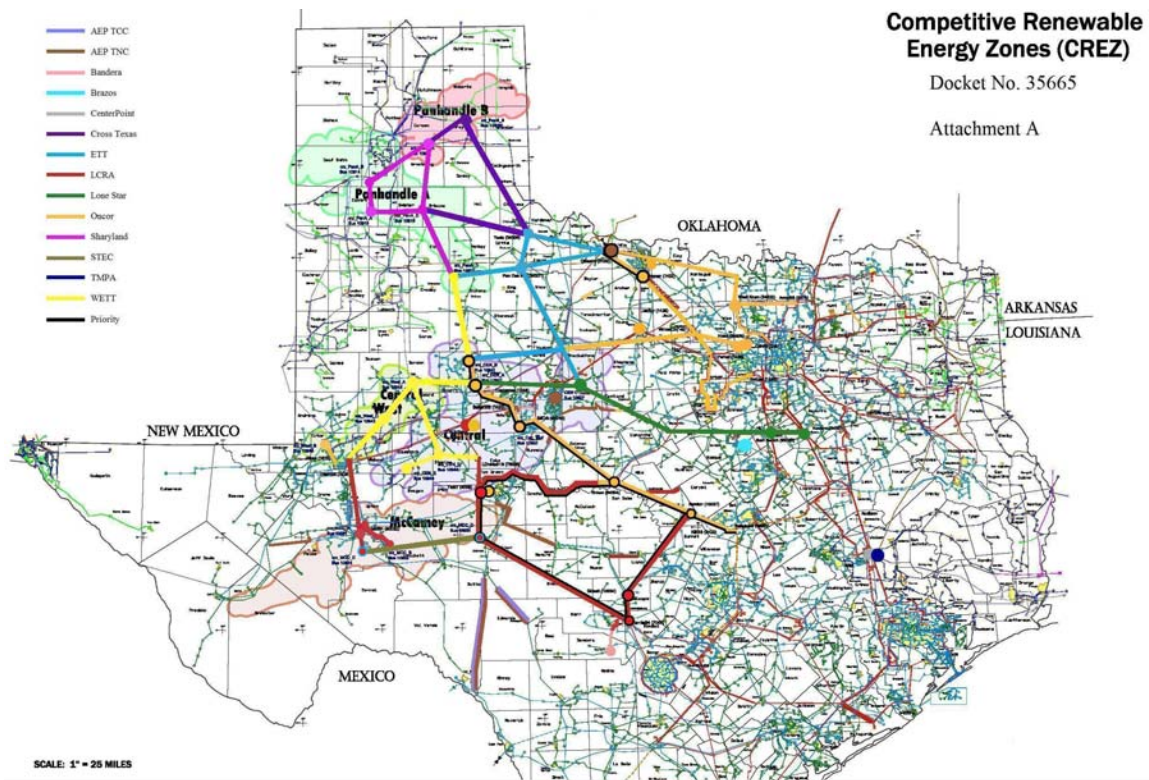
On May 15, 2009, the PUCT issued its Order on Rehearing selecting the TSPs that would be responsible for developing and constructing the various CTP facilities.²⁴ Fourteen different entities were selected to develop and construct various segments of the CTP facilities. Only one party that sought to develop and construct these facilities wasn't selected. It was an affiliate of Babcock & Brown whose share price declined precipitously and debt was downgraded below investment grade.

Three categories of CREZ projects were identified in Docket No. 33672: Default Projects; Priority Projects; and Subsequent Projects. Default Projects are those projects that refit, rebuild, or enhance existing transmission infrastructure. These projects were awarded to the TSPs that owned the existing infrastructure. A number of the CREZ Default Projects have been completed and others are in various stages of completion. The CREZ Priority Projects are those necessary to alleviate current or projected transmission congestion issues and were determined to have the highest priority for completion. The CREZ Priority Projects were awarded to two incumbent utilities, Oncor Electric Delivery LLC (Oncor) and LCRA Transmission Services Corporation (LCRA TSC). The CREZ Subsequent Projects consist of the remaining CREZ transmission projects not identified as either Default or Priority.

The major CTP facilities and the TSP that was designated to build them are identified in Figure 2. Responsibility for specific projects in the CTP was assigned to AEP Texas Central Company, AEP Texas North Company, Bandera Electric Cooperative, Brazos Power Electric Cooperative, CenterPoint Energy Houston Electric, Texas Municipal Power Agency, LCRA Transmission Services, Oncor Electric Delivery Company, Cross Texas Transmission, Electric Transmission Texas, Lone Star Transmission, Sharyland Utilities, South Texas Electric Cooperative, and Wind Energy Transmission Texas. Four of these entities can be considered new entrants: (1) Cross Texas Transmission is part of the LS Power Group, a generation and transmission project developer; (2) Electric Transmission Texas is a joint venture of subsidiaries of American Electric Power (AEP) and MidAmerican Energy Holdings Company, which are vertically integrated electric utilities with AEP having electric service territories in Texas; (3) Lone Star Transmission is a subsidiary of NextEra Energy, Inc., the competitive renewable and clean energy subsidiary of FPL Group which also owns FPL, a rate regulated utility that operates in Florida; and (4) Wind Energy Transmission Texas which is a joint venture between Brookfield Asset Management and IsoluxCorsanConcesiones, S.A., a subsidiary of IsoluxCorsan Group, a large Spanish engineering, construction services and real estate development firm.

²⁴ Parties to a proceeding are able to request a rehearing. Therefore, the PUCT issues an order on rehearing restating its decision when such requests are made.

Figure 2



3.6 CCNs and Project Development Process

With some exceptions for the enhancement of existing infrastructure, a TSP must submit its application for a transmission project to the PUCT in order to receive a CCN which allows the TSP to proceed with construction of the project and to exercise the power of eminent domain where necessary. CCN applications are contested cases that generally focus on the transmission line route that will be selected from the alternative routes proposed by the TSP. There isn't a separate environmental assessment process at which environmental issues will be considered. CCN applicants are required to identify one route as their preferred route. The PUCT may approve the CCN application by selecting one of the routes, approve it in part, or deny the application. The PUCT is statutorily required to process applications for CREZ-related CCNs within 180 days of receipt of a complete application. This expedited deadline helps to accelerate the development of those facilities and reduces the financial risks to the TSP. Once the PUCT issues an order approving a route for a transmission project, the TSP may then proceed to acquire the necessary right of way (ROW).

A majority of the CREZ Default Projects did not require a CCN and have proceeded to completion or are in the process of being completed. All of the CREZ Priority and Subsequent projects required CCN applications. With the exception of one project, which is pending, all of the CREZ Priority Project CCNs have been resolved and are proceeding toward ROW acquisition and construction. Similarly, all CCNs for the Subsequent projects (with the exception of one) have been approved by the PUCT and are proceeding towards ROW acquisition and construction. For the one application for a Subsequent project that was denied by the PUCT, ERCOT has subsequently determined that

alternative enhancements to existing transmission infrastructure could substitute for the construction of the line in the short term. The Commission is currently studying ERCOT's alternative proposal to determine if the project is still needed.

PUCT staff indicated that all of the new entrants have performed well and brought new ideas and approaches that yielded savings. In particular, one new entrant proposed spun concrete poles which reduced construction costs, accelerated construction schedules and reduced siting issues with affected landowners. With the PUCT mandated to approve or disapprove CCNs for CREZ facilities within 180 days (rather than the one year deadline typical for other projects), the PUCT organized two workshops for the new entrant TSPs to review CCN filing requirements and also provided a pre-filing review of the routing description, given its importance to the CCN process.

3.7 Differences between CREZ and Alberta CTI

There are fundamental differences between Texas' CREZ and Alberta's CTI. The CREZ was a comprehensive resource planning, investment analysis, facility selection and transmission service procurement process. The CTP facilities will represent \$5 billion (US\$) in investment in numerous separate, but interconnected transmission facilities. The CREZ process took five years from the passage of Senate Bill 20 to the filing of CCNs. A schedule of the CREZ process including the various critical PUCT decisions is provided in Appendix A.

The CREZ process was focused on enabling the required investment and significant volume of construction activity to occur over a compressed time period. The focus was on attracting capital during a time significant financial constraints and promoting innovation through the introduction of new entrants. The net result is that 14 different parties were designated as TSPs for the relevant facilities. By enabling broad participation with respect to the permitting, construction, ownership and operation of the CTP facilities, there was little competitive tension. Savings were provided by innovation rather than reductions in the cost of capital through the application of project finance.

The PUCT played a central role in the CREZ process and was assisted by ERCOT given its role as transmission planner for the market area. The AESO's role in the competitive procurement of the CTI is more limited, with a focus on determining a person who is eligible to apply for, and who ultimately assumes responsibility, in whole or in part, for all or some of designing, constructing, financing, owning and operating the new CTI.

4. UK: Regime for Tendering Offshore Wind Transmission Investment

This chapter reviews the process and decision criteria that are employed by the Office of Gas and Electricity Markets (Ofgem), the UK electricity and gas regulator, to select transmission companies to own and operate the high voltage offshore transmission facilities that are required to integrate the expected generation from offshore wind facilities.

Electricity generated from offshore wind projects is expected to make an important contribution to the achievement of the UK's share of the European Union's target of generating 20 per cent of energy from renewable sources by 2020. To enable the development of these generation resources, the

requisite offshore electricity transmission infrastructure must be developed in a timely and cost-effective manner.

One of the initial steps in this process was the awarding of offshore leases by The Crown Estate who is responsible for administering Crown-owned land in the UK. The Crown Estate announced the first round of UK offshore windfarm development in December 2000. This first round was intended serve as a “demonstration” round, enabling developers to gain necessary experience. The projects that were awarded contracts in the first round, nine projects totaling 2,064 MW, are identified in Table 1. Following the success of this first round the Department of Trade and Industry (DTI) requested The Crown Estate to begin a competitive tender process for a second round of larger sites in July 2003. Fifteen projects representing 7.2 GW were awarded Crown Estate Agreements for Lease in this second round. In June 2008, The Crown Estate announced proposals for the third round of offshore leases for windfarms totaling 32.2 GW which are targeting providing 25% of the UK’s electricity requirements by 2020.

Table 1: First Round Offshore Wind Projects

Project Name	Size (MW)	Status/COD
Barrow	90	Operational
Robin Rigg East and West	180	Operational
Gunfleet Sands 1 & 2	164	Operational
Sheringham Shoal	315	April 2011
Ormonde	150	March 2011
Greater Gabbard	504	November 2010
Thanet	300	May 2010
Walney 1	178	October 2010
Walney 2	183	August 2011
Total	2,064	

Source: Ofgem

The UK Department of Energy and Climate Change (DECC) and Ofgem have estimated that the transmission infrastructure investment to interconnect these three rounds could represent up to £15 billion, over \$23 billion US at current exchange rates.²⁵ Given the magnitude of potential investment, the UK Government found that a more dynamic approach was required to develop the transmission infrastructure and sought “an open, competitive approach that is built on encouraging innovation and new sources of technical expertise and finance.”²⁶ Ofgem notes that it “consulted extensively on the design of the competitive Tender Process”.

Ensuring that the process was as competitive as possible was a primary concern. To this end, Ofgem precluded any exclusive relationships with critical equipment vendors who could otherwise forestall competition and National Grid was precluded from participating. Ofgem noted that it would be difficult to police such a requirement.

²⁵<http://www.ofgem.gov.uk/Networks/offtrans/pdc/cdr/cons2009/Documents1/Main.pdf>

²⁶<http://www.ofgem.gov.uk/Networks/offtrans/pdc/cdr/cons2009/Documents1/Main.pdf>

4.1 Key Issues for Ofgem's Tendering Process

One of the critical issues for the tendering process developed by Ofgem was to ensure sufficient coordination between the offshore generation project developer who created the need for the offshore transmission facilities, the prospective bidders, and the National Electric Transmission System Operator (NETSO) who is responsible for determining how these facilities would connect with the existing transmission grid. These offshore transmission facilities are the sole means by which the generation project developer will be able to deliver the project's renewable energy to the grid so these facilities must be in-service on a timely basis and be reliable.

In response, Ofgem and the DECC developed and introduced a new regulatory regime for offshore electricity transmission. A key part of the new regime is that offshore electricity transmission licenses will be granted following a competitive tender process run by Ofgem. In essence, in the transitional regime the successful bidders will receive a transmission license which allows them to provide transmission services and an entitlement to an associated 20 year revenue stream in return for purchasing the transmission assets from the offshore wind generator and operating them in accordance with the obligations of the license.

The competitive tender process employed by Ofgem will result in the grant of an offshore transmission license to the successful bidder. Offshore transmission licenses include a number of special conditions which set out the specific obligations and rights of the licensee. These define, among other things, the revenue stream that the Offshore Transmission Owner (OFTO) will receive for 20 years.

Under the transitional arrangements employed for rounds one and two, generation developers construct transmission assets which are then transferred to an OFTO selected through Ofgem's tender process. Hence, construction risks remain with the generation developer. The developer transfers ownership of the completed transmission asset to a licensed OFTO at a price set by Ofgem based on the cost to construct following an assessment of costs. Ofgem assessment is of "the economic and efficient costs of developing the assets to be transferred for each project."²⁷ This assessment is necessary because these costs are not subject to the same competitive tension as they would be under the enduring regime. Therefore, for transitional projects, the role of the OFTO is to finance, own, maintain and operate an asset that has been or will be constructed by the generator developer.

Under the enduring regime that is being employed for round three, an OFTO will have the option to design and construct offshore transmission assets as well as financing, operating, maintaining and owning them or to just finance, operate or maintain the facilities.

4.2 Overview of the Process

Based on the experience in the transitional regime, Ofgem is considering amending the key stages of the enduring tender process. In order to ensure that costs are minimized for all parties, Ofgem may revise the process to identify those applicants which are best placed to participate in the Invitation to

²⁷Ofgem, "Offshore Transitional Tenders First Round Transitional Projects Tender Guidance Note on Process to Asset Transfer", pg. 6.

Tender (ITT) stage, as soon as possible. In order to identify those qualified applicants, the Pre-Qualification (PQ) stage may be made more onerous. Since the Tendering Rules from Ofgem do not yet reflect these refinements, the detailed process that will be used for the enduring regime remains unclear. Ofgem expects to issue a final decision regarding the process in December 2010.

Ofgem has not yet released details regarding the process that will be employed for the enduring regime. The information provided herein regarding the anticipated stages for the enduring regime is based on information available regarding the transitional regime. The transitional regime had the following stages:

- Pre-Qualification (PQ),
- Qualification to Tender (QTT),
- Invitation to Tender (ITT),
- Best and Final Offer (BAFO) (optional),
- Preferred Bidder, and
- Successful Bidder to whom a license would be granted

Ofgem may eliminate the QTT stage in the enduring regime.

The number of participants is reduced at each of these stages. Pre-Qualification is open to all and will produce a list of qualified bidders. The Invitation to Tender is then issued to the short list of qualified bidders. The bids are scored against criteria specified in the bid documents. Ofgem may, after evaluating the bids, ask for a Best and Final Offer, or it may directly choose a Preferred Bidder. It may also designate a reserve bidder who would be approached if Ofgem is unable to come to an agreement with the Preferred Bidder.

For the transitional regime, Ofgem developed tender rules to inform the interested parties regarding how it would run the tender process.²⁸ Prior to development of the tender rules, regulations were promulgated to provide a foundation for these tender rules.²⁹ The regulation describes the stages of the process and the application of the criteria at each stage. The regulation does not list any criteria, but does state that the criteria to be used in bid evaluation will be set out in the bidding documents.

To date, Ofgem has initiated two rounds of competitive tenders and awarded licenses for the first round under the transitional regime. The second round was initiated on November 17, 2010. The schedule for these first two transitional regime tenders is shown below in Table 2. Not surprisingly, the second round tender reflects a considerably accelerated schedule.

Table 2: Ofgem Transitional Regime Tendering Schedule

Milestone	Round One Tender	Round Two Tender
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²⁸<http://www.ofgem.gov.uk/NETWORKS/OFFTRANS/OTT/TENDOCS/Documents1/Offshore%20Electricity%20Transmission%20Tender%20Rules.pdf>

²⁹Statutory Instruments 2009 No. 1430 “The Electricity (Competitive Tenders for Offshore Transmission Licenses) Regulations 2009”. Made 1 June 2009.http://www.opsi.gov.uk/si/si2009/uksi_20091340_en_3#pt7-11g12

Tender Commencement/Pre-Qual Issued	July 22, 2009	November 17, 2010
Qualification to Tender Issued	September 24, 2009	January 25, 2011
Invitation to Tender Issued	December 22, 2009	Early April 2011
Decision on Preferred Bidder	August 5, 2010	Late July 2011

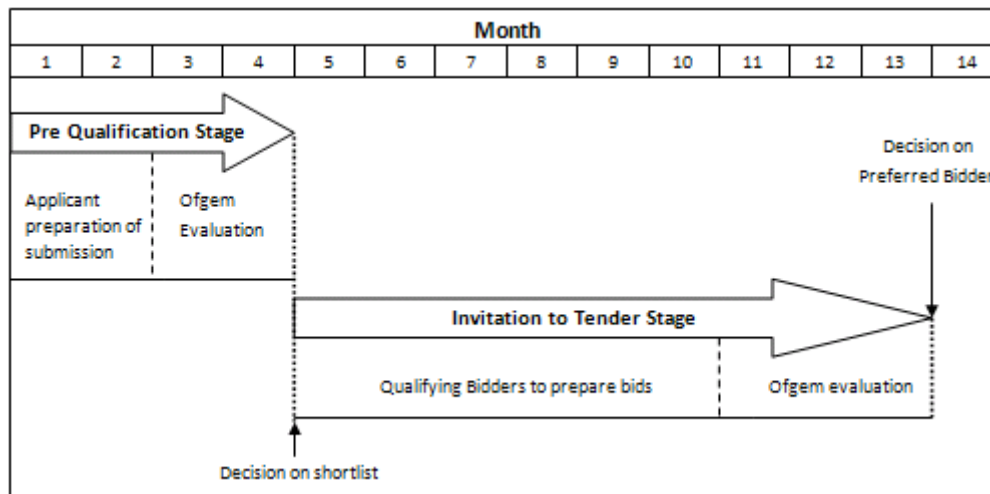
Source: Ofgem

The stage descriptions below draw on and cite the tender documents issued by Ofgem for the transitional regime. Since tender documents have not been released for the enduring regime, it isn't clear how the different criteria that are currently part of the Qualification to Tender stage will be considered as part of either the Pre-Qualification or the Invitation to Tender stages. However, we expect that many of these criteria are likely to be considered in the Pre-Qualification stage, and hence, the discussion of the criteria that were considered in the Qualification to Tender stage in the transitional regime is deferred to the discussion of the Pre-Qualification stage.

4.3 Expected Schedule

The schedule for the enduring regime is shown below in Figure 3. This schedule indicates that the process from initiation of the Pre-Qualification Stage to the Invitation to Tender Stage will take about 13 months to the end of the Invitation to Tender stage.

Figure 3: Competitive Tendering Process for Offshore Wind Transmission Investment



Source: Ofgem

4.4 Stage Descriptions

4.4.1 Pre-Qualification

As discussed, the PQ stage of the tender process may be revised to make it a more onerous single stage that would establish the short list for the ITT stage. The PQ stage would require demonstration of both past experience of designing and constructing relevant assets and the presentation of initial project specific design proposals. In order to facilitate the preparation of PQ submissions, project specific information will be made available to applicants at the start of the PQ stage in the form of a preliminary offering memorandum and in the transitional regime a sale and purchase agreement (SPA) that has been populated by the developer and provides information specific to its offshore wind project and the required transmission facilities. This information would be provided by generation developers as part of the tender entry conditions and applicants would need to sign a confidentiality agreement in order to access this information. In addition, each applicant is provided with (i) a pre-qualification questionnaire that must be completed, (ii) details regarding payments for this tender stage, and (iii) general instructions. Applicants are also required to provide £5,000 to Ofgem in this stage as earnest money and to help cover tender costs.

Applicants would be given 2 months to prepare their PQ submissions and Ofgem will require 2 months to evaluate them.

The selection is based on the applicant's economic and financial standing, legal standing, and management and operational capability.³⁰The evaluation process section from the Pre-Qualification

³⁰Ibid., pg. 12.

stage of the transitional regime, including the criteria used, is presented below drawing heavily upon the tender documents.³¹

Evaluation Process

(A) Evaluation Criteria

The purpose of the Pre-Qualification Stage is to determine those Applicants that meet the criteria to be Qualifying Applicants by assessing whether an Applicant has sufficient economic and financial standing, management and operational capability and legal standing, based on the Applicant's current standing and track record, to satisfy Ofgem that the Applicant is capable of (i) taking over ownership of the Qualifying Project(s) for which it wishes to be invited to tender and (ii) assuming the responsibilities and duties associated within being an OFTO. Where the Applicant is a consortium, this assessment will be based on the current standing and track record of the consortium taken as a whole.

Applicants are required to demonstrate through their responses to certain questions that they meet the criteria. The criteria relevant to each section of the Pre-Qualification Questionnaire are set out below, focusing on the five sections that have substantive elements.

Section 2 – Organizational structure

An Applicant must provide details and evidence of its ownership and organizational structure.

Section 3 – Economic and financial standing

An Applicant must demonstrate that it has the necessary financial strength to be considered viable to support the proposed expenditure level (on the basis of the aggregate of Ofgem's estimated transfer values for the Qualifying Project(s) for which the Applicant wishes to be invited to tender).

Section 4 – Management and operational capability

An Applicant must demonstrate that it has the necessary expertise to manage and operate an essential services asset or regulated infrastructure asset of similar size and complexity to the Qualifying Project(s) for which the Applicant wishes to be invited to tender.

Section 5 – Legal standing, pending litigation and potential conflict issues

An Applicant must demonstrate that it satisfies the minimum legal requirements in order to be granted an Offshore Transmission License, that it is not involved in any relevant material litigation and that it does not have any potential conflicts of interest which materially detract from its ability to tender for, manage and operate the nominated Qualifying Project(s).

³¹ Ofgem "Pre-Qualification Document 2009 Transitional Tenders", issued 22 July 2009, pp. 10-11. Material cited is copyrighted by the Crown.
<http://www.ofgem.gov.uk/Networks/offtrans/rott/Documents1/Pre%20Qualification%20Document%202009%20Transitional%20Tenders.pdf>

At this stage of the Tender Process, Applicants are required to provide a methodology statement for managing conflicts of interest, for information purposes only. However, Ofgem reserves the right to evaluate this information as part of future stages if the Applicant is taken forward.

Section 6 – Certificate

A duly authorized officer of the Applicant is required to confirm the statements in section 6. An Applicant who does not satisfy the criteria in section 6 will have its Pre-Qualification Submission rejected and such Pre-Qualification Submission will not be considered further. An Applicant will not be required to initial and sign where it can demonstrate that any relevant bankruptcy or other insolvency related claim is vexatious or not material in the context. In evaluating an Applicant's response to statement (C), Ofgem will consider whether an Applicant's explanation raises or fails to answer concerns over its ability to service the anticipated financial liabilities of an OFTO.

(B) Applicants are also required to provide information in response to certain questions in the Pre-Qualification Questionnaire which may be used by Ofgem to contextualize a wider evaluation.

Some of the questions contained within the Pre-Qualification Questionnaire are included in order to allow the Applicant to demonstrate that it meets the minimum legal requirements required of all licensees.³²

The Pre-Qualification document also says that the submissions will first be checked for compliance with all requirements. Then they will be evaluated against the criteria on a pass/fail basis, and all submissions which pass all of the criteria will be invited to the next (Qualification to Tender) stage.

The criteria in this stage relate to the general capability of the firm both organizationally and legally. They include questions relating to the legal status of the bidder and its potential conflicts of interest in addition to asking for demonstrations of technical competence.

4.4.2 Qualification to Tender (Transitional Regime only)

The evaluation criteria part of the Qualification to Tender document has eleven sections, of which seven contain scored criteria.³³ The first two provide general information and instructions and the last two pertain to certifications and confidentiality requirements. In the discussion below, weights are indicated for each section that deals with scored criteria. The relevant sections are quoted below. Details are retained only for the scored sections.³⁴

QTT Evaluation Criteria

Section 3 - Project IRR and Tender Revenue Stream (25% Weighting)

³²Ibid., pp. 10-11.

³³<http://www.ofgem.gov.uk/Networks/offtrans/rott/Documents1/Qualification%20to%20Tender%20Document%202009%20Transitional%20Tenders.pdf>

³⁴Ofgem, "Qualification to Tender Document 2009 Transitional Tenders", issued 24 Sept 2009. Criteria and weighting are on pp 12-13. Material is Crown copyright.

The Qualifying Applicant must provide an indicative annual Tender Revenue Stream for the relevant Qualifying Project incorporating its proposed Project IRR and other relevant assumptions.³⁵ Qualifying Applicants will be evaluated on the basis of their project IRR together with their approach to deriving the Tender Revenue Stream.

Section 4 - Financing strategy (25% Weighting)

The Qualifying Applicant must provide its proposed financing strategy. Qualifying Applicants will be evaluated on the basis of the coherence, deliverability and viability of the proposed financing strategy in support of their Project IRR and Tender Revenue Stream. The response should include evidence of support including, where appropriate, indicative terms.

Section 5 – Financial and commercial risk management (10% Weighting)

The Qualifying Applicant must demonstrate an understanding of the key risks that could have a financial and/or commercial implication for the relevant Qualifying Project. Qualifying Applicants will be evaluated on the basis of their understanding and proposed approach to managing and mitigating these.

Section 6 - Shareholding/consortium structure (5% Weighting)

The Qualifying Applicant will be evaluated on the basis of the robustness and clarity of its proposed shareholding/consortium organizational and contractual structure.

Section 7 - Management capability statement (20% Weighting)

The Qualifying Applicant must demonstrate its capabilities through experience-based management approaches to key aspects of the role to be undertaken by an OFTO and the specifics of operating within the offshore transmission regime.

Qualifying Applicants will be evaluated on the basis of their understanding of the requirements and the coherence and viability of their proposals in relation to the relevant Qualifying Project.

Section 8 - Take over and operational plan (10% Weighting)

The Qualifying Applicant must demonstrate, with regard to its management approach, its understanding and approach to acquiring a business or assets from a third party and developing and evolving an operations plan for newly acquired assets.

Qualifying Applicants will be evaluated on the basis of the coherence and deliverability of their approach in relation to the relevant Qualifying Project.

Section 9 – Sale & Purchase Agreement (5% Weighting)

The Qualifying Applicant must demonstrate its understanding of the scope and considerations associated with the Model SPA in the context of the project specific information provided through the tender process to date. The Qualifying Applicant will be evaluated based on their clear and

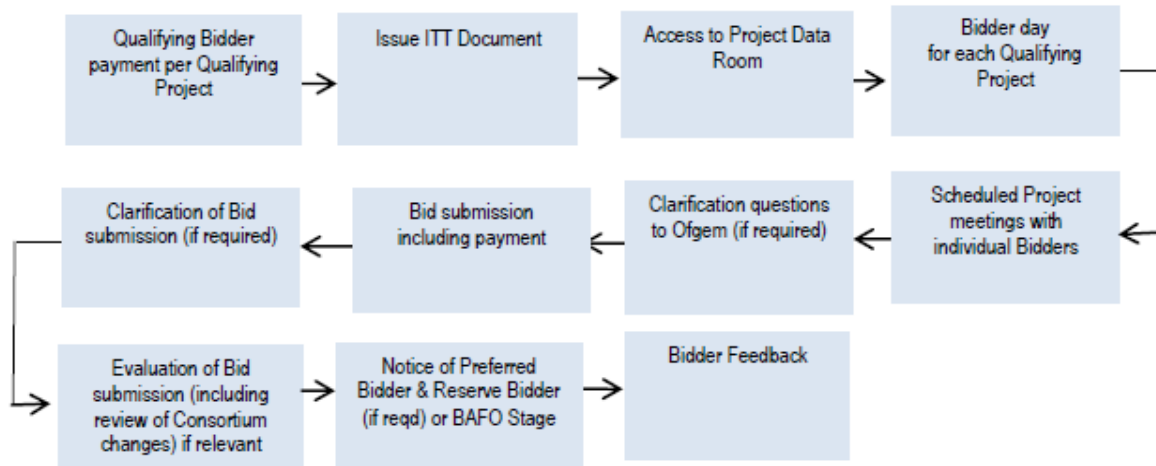
³⁵ These other relevant assumptions are not specifically identified.

considered identification of key commercial issues associated with the Qualifying Project and its transfer via an SPA. A legal markup of the Model SPA is not required.

4.4.3 Invitation to Tender

Figure 4 below summarizes the key steps in the Invitation to Tender stage.

Figure 4: Key Steps in the Invitation to Tender Stage



Source: Ofgem, Tender Rules

Ofgem found that the ITT stage for the enduring regime requires Qualifying Bidders to submit detailed design plans for the projects for which they wish to bid and that the design plan must be based on the generation developer's requirements and information provided to them regarding any preconstruction works. As part of their submissions, Qualifying Bidders may need to consider a number of issues including:

- alternative transmission asset designs;
- cable route options, appropriate AC/DC solutions;
- analysis of onshore connection points;
- ancillary services studies; and
- possible engagements with third parties such as the NETSO (in order to obtain information regarding the feasibility of proposed design plans).

After identification of the bidders on the short list, the ITT phase begins with establishment of a data room to which the short listed bidders have access.

The ITT is designed to enable the short-listed qualifying bidders to submit their detailed proposals against a number of criteria, including their required revenue stream for the project. The key elements of this stage are:

- Qualifying bidders will be provided with access to a fully populated data room for the specific project(s) for which they have been shortlisted,
- Qualifying bidders will be invited to submit a detailed bid for each project for which they have been shortlisted,
- Assessment will be based on the qualifying bidders' responses against a number of detailed criteria, including their required revenue stream and their managerial, operation and legal capability,
- Assessment will be on a scored basis against the criteria,
- Where a qualifying bidder has been shortlisted for more than one project, they will be required to submit an ITT bid for each project individually but may also submit a variant bid for a combination of projects. However, any variant bid submitted must, at a minimum, identify the required revenue stream on a per project basis, and
- Where a qualifying bidder wishes to change its consortium, it must notify Ofgem, who will use its discretion to permit the change having regard to whether the change would be fair and equitable to all other qualifying bidders for that project.

The outcome of the ITT Stage will be the identification of the Preferred Bidder for each project. Ofgem's selection of proposals is based on a 60/40 price/non-price weighting. Where appropriate, a Best and Final Offer Stage will be run to identify the Preferred Bidder. The Best and Final Offer Stage can be used to bid against a limited number of revised issues. This stage would take one month in total. Once the Preferred Bidder is appointed, the time to license award would vary on a case by case basis, depending on project specific issues.

4.5 Performance Incentive

Under the existing mechanism 10% of the licensee's yearly base revenue is exposed to a performance incentive for availability. The incentive reflects a target monthly availability of 98% (having adjusted for factors beyond the OFTO's control). The objective is to ensure that planned and unplanned outages should occur, on average, in no more than 2% of a relevant period. A maximum penalty/collar (i.e., 10%) determines the maximum proportion of an OFTO's revenue stream which may be exposed to the performance incentive in each period and a system of performance credits and debits incentivizes the OFTO to improve performance in excess of the availability target and, without adversely impacting on financial viability, maintains incentives to restore availability once the collar has been met.

4.6 Results of Competitive Tender

Ofgem selected Balfour Beatty Capital, Macquarie Capital Group and Transmission Capital Partners as winners of a competitive tender, to own and operate the first seven out of nine offshore transmission links. Ofgem reported that investor appetite for offshore wind transmission projects is currently greater than the pipeline in the UK. Ofgem said strong competition has attracted almost £4billion of investment proposals for the nine transmission links, which it said are only worth around £1.1billion. The competitive tendering process produced savings of approximately £350 million.³⁶

³⁶http://www.oilvoice.com/n/Ofgem_Launches_3bn_UK_Offshore_Wind_Transmission_Tender/1a0b6861c.aspxThis figure was confirmed by Stephen Beel of Ofgem (Phone Conversation November 30, 2010.)

³⁷The appetite represented offers of commitment from equity, corporate finance and commercial debt finance providers as well as European Investment Bank funds. There were five consortia pursuing the transmission assets, with 13 pre-qualified entities. The success of this process is causing Ofgem to consider its application for major onshore transmission investments.

At the time of this announcement a Best and Final Offer process was to be run for the Ormonde facilities (Transmission Capital Partners was subsequently identified as the preferred bidder) and the ITT was to be rerun for the Great Gabbard facilities with four bidders participating, two of which hadn't been awarded licenses.

4.7 Conclusions

Ofgem's competitive procurement process is patterned after the process that is typically used for the sale of generation assets. The first round is a qualifications process which focuses on identifying a short list of interested parties. Critical issues in the selection of the short list are ensuring that the parties have the required financial capability to close the transaction and the technical capability to operate the asset. Indicative bids are used as a measure of the parties' initial estimate of the value of the asset, but are subject to additional due diligence and further analysis. Where's the purchase price offered is typically the primary consideration in selecting the asset buyer, Ofgem employed a broader range of considerations given the importance in ensuring that the OFTO has the required capability. To the degree that Ofgem develops greater confidence in the depth of qualified prospective bidders, it may elect to more heavily weigh the tender revenue stream in future tenders.

Recognizing that the discussion above is based on the tender documents applicable to the transitional regime, Power Advisory anticipates that the stages and criteria for the enduring regime would be modified to reflect the greater scope of responsibility for the successful bidder (*e.g.*, designing transmission facilities to deliver the output of the generation, obtaining permits for the construction and operation of the transmission facilities, potentially greater coordination with the generation developer, etc.). Given the relatively specialized nature of these transmission projects (and the large amount of generation investment that will be dependent on the timely completion and reliable operation of the transmission facilities), relatively high weights may be assigned to the technical and construction capabilities of the applicants.

5. Ontario: Transmission Development Planning Guidelines

With the passage of the *Green Energy and Green Economy Act, 2009* (GEGEA), Ontario has committed to the aggressive development of renewable energy resources under a Feed-in Tariff (FIT). However, the ability of existing and approved transmission facilities in Ontario to accommodate more generation is limited. In September 2009, the Minister of Energy and Infrastructure requested that Hydro One Networks, Inc., which owns the vast majority of transmission in the province, begin development work on twenty transmission facilities that would enable the development and interconnection of more renewable energy resources. Recently, the Ministry of Energy released its

³⁷The £350m savings were calculated by comparing the average annual revenue bids for the nine offshore transmission links (based on the bids received) with the annual revenues allowed for onshore Transmission Owners during the last transmission price control review.

Long Term Energy Plan which indicated that of these twenty potential projects five projects were being actively pursued, one of which will be subject to the designation process outlined below. Significant investment in transmission infrastructure will be required to accommodate current FIT applicants as well as future renewable generation projects.

As a result of the *GEGEA*, the *Ontario Energy Board Act* contains new provisions that require licensed transmitters, when mandated by the Board, to develop transmission plans for review and approval by the Board. The Board issued its policy with regard to transmission project development planning in August 2010.³⁸ Thereby outlined its objectives as to:

- allow transmitters to move ahead on development work in a timely manner;
- encourage new entrants to transmission in Ontario bringing additional resources for project development; and
- support competition in transmission in Ontario to drive economic efficiency for the benefit of ratepayers.³⁹

This policy was part of an effort by the OEB to provide greater regulatory predictability given the magnitude of anticipated transmission investment and reflects the belief by the OEB that the currently regulatory framework serves both customers and utilities well.

The general approach outlined by the OEB is to conduct a formal hearing to designate a transmitter that will be responsible for undertaking the development of a specific transmission facility. New entrant transmitters (entities that don't already own and operate transmission facilities in Ontario) must be licensed in order to participate in the designation process. The licensing process allows the OEB to evaluate the financial viability and technical capabilities of the new entrant transmitters.

The designation process would be used for enabler facilities (i.e., transmission facilities that would connect clusters of renewable generators to the existing transmission network) and network expansions (i.e., expansion of the network through major new network facilities).⁴⁰

In its role as the transmission planner for Ontario, the Ontario Power Authority will administer an Economic Connect Test (ECT) to determine which transmission system investments are needed to connect economically a FIT project. The results of the ECT will be used to identify the enabler facilities and network expansions that would be developed by designated interested transmitters. Specifically, when the OEB receives the results of the ECT from the OPA, it will begin a competitive process to designate a transmitter to undertake development on any new enabler facilities or network expansions identified. If a recently approved Integrated Power System Plan is available, the transmission recommendations contained in that plan may be used for the designation process.

All licensed transmitters will be invited to submit plans in the form outlined by the OEB's filing requirements, with a deadline for filing plans ranging from three (the default period) to six months

³⁸ Ontario Energy Board, *Board Policy: Transmission Project Development Plans*, (EB-2010-0059), August 26, 2010.

³⁹ OEB, *op. cit.*, p. 1.

⁴⁰ As implied, this process doesn't apply to the reinforcement of existing network facilities. To promote a greater role for competition, new lines on existing or widened corridors are viewed as expansions, and thus, may be developed through a competitive process.

(for more complex facilities). Only the transmitter that is successful in being designated will be able to recover the costs of preparing a plan. If no plans are received for a project, the incumbent will be directed to file a plan and would be able to recover the costs of plan preparation. Thus, the preparation, submission and evaluation of the project-specific plans is, in effective, the competitive process for identifying the preferred transmission developer.

The OEB will designate a transmitter based on the evidence in the proceeding regarding the proponent's organization and experience, technical capability, financial capacity, schedule, costs, landowner and other consultations. The specific filing requirements are outlined by the OEB in a separate document.⁴¹ The OEB's assessment will take into account the individual circumstances of the project. The general information required along with the elements of the OEB's evaluation of applicants are reviewed below.

Technical capability is assessed in terms of the Applicant's ability to engineer, plan, construct, operate and maintain the project, based on experience with projects of equivalent nature, magnitude and complexity.

Financial capability is assessed in terms the applicant's financial capability necessary to develop, construct, operate and maintain the project. In addition, the applicant is required to demonstrate its existing financial capacity, its ability to access the debt and equity markets and the terms and conditions of any financing.

The applicant is also required to submit a project development schedule identifying major development milestones and proposed dates for completing those milestones, as well as a project construction schedule identifying major construction milestones and proposed dates for completing those milestones. The proposed schedules and milestones will be reviewed and assessed by the OEB.

With respect to costs, the Applicant is required to provide: (1) an estimated budget for the development of the project up to the submission of the leave to construct application; (2) an estimated budget for any further development of the project after leave to construct has been granted; (3) an estimated budget for the construction of the project; and (4) the estimated average annual cost of operating and maintaining the project.

Finally, the Applicant must demonstrate the ability of its management team to conduct successful consultations with landowners, First Nations and Métis and other relevant parties.

The transmitter designated for a particular project will be assured of recovery of the budgeted amount for project development through the submission of the leave to construct. Material overages will be at risk until a future prudence review. When subsequent analysis by the OPA suggests that the project has ceased to be needed or is no longer economically viable, the transmitter will be entitled to appropriate wind-up costs.

⁴¹ Ontario Energy Board, Filing Requirements: Transmission Development Plans, August 26, 2009.

The Board order of designation will have conditions such as performance milestones based on the project schedules (in particular, a deadline for submission of the application for Leave to Construct) and reporting requirements on progress and spending that, if not met, will result in the designation being rescinded and will put further expenditures at risk. Final project selection will take place after the application for Leave to Construct has been submitted.⁴²

5.1 Differences between the OEB's Designation Process and Alberta CTI

The process that the OEB has outlined for designating transmitters applies only to the transmission development planning for the relevant facilities. These development costs are likely to represent from 5 to 10% of the total project costs. While it is likely that the designated transmitter will have a competitive advantage when seeking to construct the required facilities, designation as the transmitter to develop a facility doesn't guarantee that the transmitter will receive approval under the leave to construct process. As such there is a need to consider the critical issues regarding the capabilities of the transmitter to finance, construct and maintain the required transmission facilities.

6. Transmission Procurement in Brazil

6.1 Overview of Process

Brazil has implemented a competitive bidding process to assign the rights to construct, own and operate transmission facilities. Under the Brazilian system, utility companies may compete in auctions for long-term contracts to construct, own and operate transmission facilities with rights guaranteed as long as thirty years. The practice began in 1999, when federal agencies started auctioning concessions to private transmission developers. In 2004, Law 10.848 reinforced the concept by establishing auctions as the primary procurement mechanism for new generation projects.⁴³ The auction system serves as an important policy initiative to stimulate investment in Brazil's transmission infrastructure and rectify its systemic weaknesses.

The auctions are part of the Transmission Expansion Program (PET) enunciated by the state-directed Energy Research Company (ERE) and the Plan of Transmission and Reinforcement (PAR) set by the National Electric System Operator (ONS).⁴⁴

These policies emphasize three objectives to strengthen the grid:

- Plan viable and cost-effective transmission expansion projects;
- Encourage competition for transmission rights; and
- Reduce barriers for new developers entering the market.

The auctions are managed by the Electricity Regulatory Agency (ANEEL) and planned by the subsidiary Power Commercialization Chamber (CCEE). The process is open to public, private, and international developers. Parties must first submit an application to ANEEL and found to be

⁴² The Leave to Construct is issued by the OEB and it focuses primarily on the need for the facility. There is a separate Environmental Assessment process which is typically conducted after the Leave to Construct.

⁴³<http://web.ing.puc.cl/~power/paperspdf/IAEE2010.pdf>

⁴⁴<http://www.aneel.gov.br/area.cfm?idArea=585&idPerfil=12>

qualified. Companies may participate individually or as a consortium. The winning bidder for each auction is determined on the basis of lowest annual revenue requirements.

6.2 Institutional Context

The Ministry of Mines and Energy (MME) is responsible for energy policy in Brazil. The MME carries out studies and planning while the control, design, and implementation over policies falls to the regulator.⁴⁵ Hydroelectric power satisfies over 80% of demand and produces nearly 90% of electricity generated nationally. A significant share of power comes from the 14 GW Itaipu Dam, a joint enterprise shared with Paraguay, accounting for 25% of all Brazil's generation. Despite abundant water-based resources, the country has only partially realized its hydroelectric potential and remains a net importer of electricity.⁴⁶ As generation expands, the transmission network will face the persistent challenge of connecting the multitude of power sources in the interior with population and industrial centers in the East.

Since the late 1990s, the Brazilian government has gradually pushed for increased private investment in energy. Private ownership, however, has mostly applied to generation, as the transmission network is almost exclusively controlled by state corporations. Eletrobrás, the dominant public utility, owns and operates two-thirds of the country's transmission capacity. In recent years, the rapid growth of Brazil's generating capacity has fueled the need for transmission upgrades. Additionally, a massive blackout in November 2009 only heightened concerns over the country's long-term resource sufficiency. An abrupt failure in the grid connected to the Itaipu Dam caused power outages in 18 of 26 states, São Paulo and Rio de Janeiro, and most of Paraguay. Although downplayed by state officials, the incident suggested a greater, inherent vulnerability in Brazil's interconnected transmission system.⁴⁷

6.3 The Auction Framework

The CCEE, under the oversight of ANEEL, designs periodic auctions for designated transmission investments. ANEEL conducts the auction using a silent bid, sealed letter format. The bidder proposing the lowest revenue requirement over the lifetime of the contract is selected and wins the right to construct the transmission project.⁴⁸

ANEEL describes the following rules:

The financial offer with the value of the Allowed Annual Revenue (RAP) for each lot must be submitted in a sealed envelope by the participant. If the difference between the lowest bid and other bids is greater than 5%, the lowest bidder wins the tender. If the difference is less than or equal to 5% or if there is a tie among the lowest bids, the auction continues, with

⁴⁵http://www.ieee.org/portal/cms_docs_pes/pes/subpages/meetings-folder/2004_Denver/Track1/Pres_4-Brazil.pdf, p. 4

⁴⁶http://www.aneel.gov.br/biblioteca/trabalhos/trabalhos/Artigo_003_Serrato.pdf, p. 4

⁴⁷<http://www.nytimes.com/2009/11/12/world/americas/12brazil.html>

⁴⁸ ANEEL defines Average Revenue Allowed as "the annual revenue the developer the bearer is entitled for the provision of public transmission service to users from the commercial operation of the facility. Its value is that obtained as a result of the auction, with annual update by the Consumer Price Index (IPCA) of the Brazilian Institute of Geography and Statistics (IBGE) and review, every five years, under a concession contract."

http://www.aneel.gov.br/aplicacoes/noticias_area/dsp_detalheNoticia.cfm?idNoticia=3552

successive moves made on the speakerphone. The director of the auction session may set minimum amounts to be provided between a bid and others. The bidder submitting the lowest value wins. In case of any bidder bids on speakerphone, that who has submitted the lowest per envelope will be the winner. If there is a tie in figures submitted by envelope without speakerphone, the winner will be determined by lottery promoted by the director of the session.⁴⁹

Contracts typically grant concessions spanning up to 30 years. The winning RAP covers the entire cost of development, maintenance, and repairs throughout the contract term. Upon completion of the project, the ONS assesses penalties for periods of inoperability. Additionally, the contract holder is obligated to satisfy interconnection requests from generators, distributors, and other transmission developers. The company is entitled to payments for such interconnections and may sign bilateral agreements with customers.⁵⁰

Historically, ANEEL has announced auctions intermittently according to its planning and development schedule. In 2009, auctions for 3,400 km of transmission projects were held in March and November. In 2010, auctions for 2,000 km were held in June and September with another auction for 700 km scheduled in December.

6.4 Selection of Developers

Transmission developers must demonstrate legal, financial, and technical competencies to merit consideration. ANEEL also includes provisions for financial interests and non-developer entities.

Investors and other groups must demonstrate minimum qualifications:

The participation in the auction is franchised to any interested party (institution), even to investors or companies that do not operate in the electricity sector, and in this case, they should demonstrate technical qualification to operate and keep the development by assigning a qualified technical person in charge...The participants should be previously qualified, according to the terms of the invitations to bid, and should constitute, if they win, a partnership of specific proposal, in order to explore the concession, if they are not the transmission concession holders.⁵¹

Several months prior to auction, ANEEL will announce a shortlist of eligible participants. To enter the auction, parties then submit a Bid Guarantee equaling 1% of the estimated investment value of the contract. Upon completion, the winning bidder must deposit a guarantee of 5% of the investment value.

6.5 Success of Program

The auction system has been highly successful in procuring transmission projects. Since 1999, auctions have been responsible for at least 20,000 km of transmission projects totaling over \$13

⁴⁹http://www.aneel.gov.br/aplicacoes/noticias_area/dsp_detalheNoticia.cfm?idNoticia=3611

⁵⁰http://www.aneel.gov.br/biblioteca/trabalhos/trabalhos/Artigo_003_Serrato.pdf, p. 9-13

⁵¹<http://www.aneel.gov.br/area.cfm?idArea=585&idPerfil=12>

billion. According to ANEEL, more than half of the projects bid to 2007 are operational with most of remaining under scheduled development. ANEEL touts the high level of participation as indicative of a robust competitive process.⁵² In recent auctions, twenty to thirty firms have participated, mostly originating from South America, Spain, and Portugal.

Potential questions relate to optimal auction design and the competitive balance of companies. Despite a prequalification process, the process has allowed parties to participate who have been unable to deliver. In response, ANEEL has explicitly blocked certain companies from participation for apparent rules violations.⁵³ There is evidence of consolidation in the market. Several state corporations in Brazil have bolstered their influence by purchasing smaller private firms in recent years. Moreover, Chinese transmission giant, the state-owned State Grid Corporation, has recently agreed to purchase seven Spanish-owned and Brazilian-based transmission firms.⁵⁴

7. Implications for AESO's Competitive Procurement Process for CTI

In its Discussion Paper, the AESO outlined two alternatives: the Own Alternative and EPC Alternative, which were reviewed briefly in the second chapter. Both the PUCT and Ofgem implemented competitive procurement frameworks that employed the "Ownership" model where the successful bidder ultimately owns and operates the transmission facilities. Power Advisory believes that this outcome isn't surprising since much of the value of a competitive process arises from the competition to "finance and own", where proponents primarily compete on the basis of their cost of capital, with additional (and important) competitive benefits from competition to "construct". Under Ofgem's transitional regime, the economic focus is almost exclusively on the cost savings from the competition to finance. Operating and maintenance costs are considered but since these costs typically represent a relatively small portion of the project's total cost of service, they ultimately receive less weight than the financing costs. As discussed further below, the process employed by the PUCT didn't fully consider the potential differences among bidders with respect to financing and construction costs, given the large number of capital intensive projects that were to be completed in a compressed time period.

The savings from competition to design and permit are real, but must be weighed relative to the potential incremental risk premiums that would added to the estimated capital cost (with a resulting increase in the project's revenue requirements) as bidders seek to manage the uncertainty associated with the design and route of the facilities.

7.1 Contrasting the PUCT and Ofgem Processes

There are a considerable number of differences between the competitive procurement processes employed by the PUCT and Ofgem. These differences stem in large part from the magnitude of required investment (almost \$5 billion for the CREZ facilities over a compressed time period, with multiple projects being "bid out" in parallel) and the scope of the required facilities (i.e., fewer routing options for offshore transmission facilities and as a result greater certainty regarding routing).

⁵²http://www.aneel.gov.br/aplicacoes/noticias_area/dsp_detalheNoticia.cfm?idNoticia=3552

⁵³http://www.bnamericas.com/news/electricpower/Aneel_shortlists_27_for_transmission_auction

⁵⁴http://www.chinadaily.com.cn/bizchina/2010-05/19/content_9867687.htm

The most significant difference between these two processes is that the PUCT's selection process focused primarily on financial capability of the bidder, given that the cost of service for the required facilities would be established at a later date pursuant to traditional cost-of-service ratemaking. Whereas, Ofgem's process considered a broader range of capabilities and considerations and most importantly, required the bidders to commit to a specific revenue requirement for the facilities. As a result, Ofgem's process resulted in greater competitive tension where proponents effectively bid their cost of capital and construction costs (under the enduring regime). As such, ensuring the competitiveness of the tender process was more critical for Ofgem.

The process employed by Ofgem is patterned after the process typically used for generation asset sales and has proven to be effective in securing value for sellers. Using a two-stage process simplifies the administration of the process, by limiting the participation in the second round (when considerably more administrative support is required) to qualified bidders.

The selection process employed by the PUCT was considerably less transparent than used by Ofgem in the UK. In particular, while the PUCT clearly outlined the evaluation criteria that it would use to evaluate interested TSPs, the weighting of those criteria wasn't clearly identified. Ultimately, the PUCT's evaluation was primarily on the basis of financial capability, with facilities awarded to all parties that were deemed qualified to bid. The large number of selected bidders helped to ensure the availability of sufficient financial and technical resources to achieve the aggressive completion schedule for the \$5 billion worth of investment required by the CREZ facilities.

Table 3 below summarizes and compares the allocation of certain project risks, and the sources of competitive efficiencies, in the competitive procurement processes used by the PUCT and Ofgem.

Table 3: Comparison of Allocation of Selected Risks and Sources of Efficiencies in Competitive Procurement Processes

Jurisdiction	Texas	United Kingdom	
Characteristic\Regime	CREZ	Transitional	Enduring
Bidders responsible for developing transmission?	Yes	No	Yes
Bidders responsible for demonstrating proposed route is the best alternative?	Yes	No	Yes
Bidders bear construction cost risks?	Limited	No	Yes
Scope for design/technology innovation by bidders	Yes	No	Yes
Presence of performance/availability incentives	No	Yes	Yes

Ofgem’s enduring regime represents one end of the spectrum, in that the winning bidder may be responsible for the design, routing, permitting, construction, financing, operation and maintenance of the facilities required to meet the identified transmission need, all in exchange for contractual revenue that is fixed at the time of contract award. Hence, the winning bidder would bear all of the development, construction, financing and ownership risks, and the revenues stream proposed by the bidders will reflect their assessment (and valuation) of those risks. While this regime reduces risks to the ultimate ratepayers (and increases the scope and scale of competitive pressures on the bidders), it may result in higher expected costs, due to the transfer of risk to bidders.

At the other end of the spectrum, Ofgem’s transitional regime removes the development risks from the bidders, since they would be taking ownership of completed transmission assets. In this regime, risks and competitive pressures are focused on the financing and ownership of the completed transmission assets, resulting in a simplified competitive process, but with reduced opportunities for efficiencies and cost savings from competitive tensions in the development stage.

The CREZ regime represents an intermediate framework, with relatively greater emphasis on transferring risks to bidders in the development stage, and less risk (and competition) in the financing and ownership of the assets (*e.g.*, winning bidders for the CREZ facilities did not need to value or internally price long-term interest rate risk, due to the planned use of traditional cost-of-service ratemaking). Similarly, the absence of performance incentives (and penalties) places the operational risks on the Texas ratepayers, rather than the assets owners.

Greater transparency allows bidders to better assess tradeoffs associated with better scores on different evaluation criteria. Specifically, bidders are better able to understand the most important areas on which they should focus when preparing their proposals and whether further technical analysis of CTI project alternatives would significantly enhance their proposal. On the other hand, less transparency with respect to the specific weights for the evaluation criteria would provide the AESO with greater flexibility when assessing proposals. Since (a) the first CTI competitive process will be the AESO’s first competitive transmission procurement process and (b) it is difficult to

anticipate differences among bidders and thus, the weights that should be assigned to these differences, greater flexibility in the evaluation criteria may be appropriate.

Appendix A: Key Dates for the CREZ Process

- 2005: Senate Bill 20 enacted which directs the PUCT to implement CREZ
- 12/1/06: ERCOT files CREZ alternatives with the PUCT
- 12/1/06: CREZ Rule adopted by PUCT outlining process for establishing CREZs
- 11/07: Interim order issued designating CREZs in five areas
- 4/2/08: ERCOT files study with PUCT with four scenarios identifying transmission required for CREZs designated by the PUCT
- 5/15/08: Petition by PUCT staff to commence proceeding to select Transmission Service Providers (TSPs) to build CREZ Transmission
- 5/22/08: Order Adopting Rules for Selecting TSPs for CREZ Transmission issued
- 7/17/08: PUCT selects CREZ scenario 2, providing over 18,000 MW of wind generation and costing approximately \$4.9 billion
- CREZ's selected based on renewable energy resource potential and the level of financial commitment by generators for each potential CREZ, including deposits for interconnection agreements and studies, financial commitments to landowners
- 7/21/08: Statements of Interest Filed by TSPs
- 9/08: Parties interested in being designated as TSPs for CREZ facilities filed detailed CREZ Transmission Plans
- 10/7/08: PUCT issues final order: Order on Rehearing Designating CREZs
- TSPs required to file Certificate of Convenience and Need (CCN) Applications within 12 months of this order (10/7/09)
- 11/6/08: Default projects (upgrades or modifications) assigned to incumbent TSPs
- 12/1 – 12/5/08 Hearings on the merits of specific TSPs building CREZ Transmission
- 3/30/09: PUCT issued Final Order establishing two dockets for sequencing and scheduling: Priority Projects CCNs due October 7, 2009; ERCOT to establish sequencing schedule within 60 days for “Subsequent Projects”
- 5/15/09: Final Order on Rehearing Designating TSPs for CREZ facilities
- 5/29/09: ERCOT files sequencing recommendations for CREZ Transmission facilities

10/7/09: Deadline for Filing CCNs for priority projects (i.e., projects that will also relieve congestion that is preventing the delivery of energy from existing wind projects)

TSPs that fail to file CCN within the deadline may have this designation revoked

There is 181 day deadline for the PUCT for processing CCNs

45 days after CCN filed Developers are required to post a letter of credit or other collateral equal to 10% of the developer's pro rata share of the cost of the CREZ Transmission facilities. Direction provided in specific docket regarding which CREZ transmission facilities will trigger specific developers to provide security.

12/31/2013 Final CREZ Transmission Facilities scheduled to be in-service